(v) The parametric testing that will be conducted to determine the reason or reasons for the failure of the unit to achieve the applicable emission limitation and to verify the proper operation of the installed NO_X emission control system during the demonstration period. The tests shall include tests in § 76.15, which may be modified as follows:

(A) The owner or operator of the unit may add tests to those listed in § 76.15, if such additions provide data relevant to the failure of the installed NO_X emission control system to meet the applicable emissions limitation in § 76.5, 76.6, or 76.7; or

(B) The owner or operator of the unit may remove tests listed in § 76.15 that are shown, to the satisfaction of the permitting authority, not to be relevant to NO_X emissions from the affected unit; and

(C) In the event the performance guarantee or the NO_X emission control system specifications require additional tests not listed in § 76.15, or specify operating conditions not verified by tests listed in § 76.15, the owner or operator of the unit shall include such additional tests.

(3) In accordance with § 76.10(d)(10), the following information for the operating period:

(i) The average NO_X emission rate (in lb/mmBtu) of the specific unit;

(ii) The highest hourly NO_X emission rate (in lb/mmBtu) of the specific unit;

(iii) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with part 75 of this chapter;

(iv) Total heat input (in mmBtu) for the unit for each hour of operation, calculated in accordance with the requirements of part 75 of this chapter; and

(v) Total integrated hourly gross unit load (in MWge).

(b) A petition for an alternative emission limitation shall include the following information in accordance with § 76.10(e)(6).

(1) Total heat input (in mmBtu) for the unit for each hour of operation, calculated in accordance with the requirements of part 75 of this chapter;

(2) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with the requirements of part 75 of this chapter; and

(3) Total integrated hourly gross unit load (MWge).

(c) *Reporting of the costs of low NO_X burner technology applied to Group 1, Phase I boilers.* (1) Except as provided in paragraph (c)(2) of this section, the designated representative of a Phase I unit with a Group 1 boiler that has installed or is installing any form of low NO_X burner technology shall submit to the Administrator a report containing the capital cost, operating cost, and baseline and post-retrofit emission data specified in appendix B to this part. If any of the required equipment, cost, and schedule information are not available (e.g., the retrofit project is still underway), the designated representative shall include in the report detailed cost estimates and other projected or estimated data in lieu of the information that is not available.

(2) The report under paragraph (c)(1) of this section is not required with regard to the following types of Group 1, Phase I units:

(i) Units employing no new NO_X emission control system after November 15, 1990;

(ii) Units employing modifications to boiler operating parameters (e.g., burners out of service or fuel switching) without low NO_X burners or other emission reduction equipment for reducing NO_X emissions;

(iii) Units with wall-fired boilers employing only overfire air and units with tangentially fired boilers employing only separated overfire air; or

(iv) Units beginning installation of a new NO_X emission control system after August 11, 1995.

(3) The report under paragraph (c)(1) of this section shall be submitted to the Administrator by:

(i) 120 days after completion of the low NO_X burner technology retrofit project; or

(ii) May 23, 1995, if the project was completed on or before January 23, 1995.

§ 76.15 Test methods and procedures.

(a) The owner or operator may use the following tests as a basis for the report required by § 76.10(e)(7):

(1) Conduct an ultimate analysis of coal using ASTM D 3176–89 (incorporated by reference as specified in § 76.4);

(2) Conduct a proximate analysis of coal using ASTM D 3172–89 (incorporated by reference as specified in § 76.4); and

(3) Measure the coal mass flow rate to each individual burner using ASME Power Test Code 4.2 (1991), ''Test Code for Coal Pulverizers'' or ISO 9931 (1991), ''Coal—Sampling of Pulverized Coal Conveyed by Gases in Direct Fired Coal Systems'' (incorporated by reference as specified in § 76.4).

(b) The owner or operator may measure and record the actual NO_X emission rate in accordance with the requirements of this part while varying the following parameters where possible to determine their effects on the emissions of NO_X from the affected boiler:

(1) Excess air levels;

(2) Settings of burners or coal and air nozzles, including tilt and yaw, or swirl;

(3) For tangentially fired boilers, distribution of combustion air within the NO_X emission control system;

(4) Coal mass flow rates to each individual burner;

(5) Coal-to-primary air ratio (based on pound per hour) for each burner, the average coal-to-primary air ratio for all burners, and the deviations of individual burners' coal-to-primary air ratios from the average value; and

(6) If the boiler uses varying types of coal, the type of coal. Provide the results of proximate and ultimate analyses of each type of as-fired coal.

(c) In performing the tests specified in paragraph (a) of this section, the owner or operator shall begin the tests using the equipment settings for which the NO_X emission control system was designed to meet the NO_X emission rate guaranteed by the primary NO_X emission control system vendor. These results constitute the ''baseline controlled'' condition.

(d) After establishing the baseline controlled condition under paragraph (c) of this section, the owner or operator may:

(1) Change excess air levels ±5 percent from the baseline controlled condition to determine the effects on emissions of NO_X, by providing a minimum of three readings (e.g., with a baseline reading of 20 percent excess air, excess air levels will be changed to 19 percent and 21 percent);

(2) For tangentially fired boilers, change the distribution of combustion air within the NO_X emission control system to determine the effects on NO_X emissions by providing a minimum of three readings, one with the minimum, one with the baseline, and one with the maximum amounts of staged combustion air; and

(3) Show that the combustion process within the boiler is optimized (e.g., that the burners are balanced).

APPENDIX A TO PART 76—PHASE I AFFECTED COAL-FIRED UTILITY UNITS WITH GROUP 1 OR CELL BURNER BOILERS

TABLE 1—PHASE I TANGENTIALLY FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	EC GASTON	5	ALABAMA POWER CO.
GEORGIA	BOWEN	1BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	2BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	3BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	4BLR	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB1	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB2	GEORGIA POWER CO.
GEORGIA	WANSLEY	1	GEORGIA POWER CO.
GEORGIA	WANSLEY	2	GEORGIA POWER CO.
GEORGIA	YATES	Y1BR	GEORGIA POWER CO.
GEORGIA	YATES	Y2BR	GEORGIA POWER CO.
GEORGIA	YATES	Y3BR	GEORGIA POWER CO.
GEORGIA	YATES	Y4BR	GEORGIA POWER CO.
GEORGIA	YATES	Y5BR	GEORGIA POWER CO.
GEORGIA	YATES	Y6BR	GEORGIA POWER CO.
GEORGIA	YATES	Y7BR	GEORGIA POWER CO.
ILLINOIS	BALDWIN	3	ILLINOIS POWER CO.

TABLE 1—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
ILLINOIS	HENNEPIN	2	ILLINOIS POWER CO.
ILLINOIS	JOPPA	1	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	2	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	3	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	4	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	5	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	6	ELECTRIC ENERGY INC.
ILLINOIS	MEREDOSIA	5	CEN ILLINOIS PUB SER.
ILLINOIS	VERMILION	2	ILLINOIS POWER CO.
INDIANA	CAYUGA	1	PSI ENERGY INC.
INDIANA	CAYUGA	2	PSI ENERGY INC.
INDIANA	EW STOUT	50	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	60	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	70	INDIANAPOLIS PRW & LT.
INDIANA	HT PRITCHARD	6	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	1	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	2	INDIANAPOLIS PWR & LT.
INDIANA	WABASH RIVER	6	PSI ENERGY INC.
IOWA	BURLINGTON	1	IOWA SOUTHERN UTL.
IOWA	ML KAPP	2	INTERSTATE POWER CO.
IOWA	RIVERSIDE	9	IOWA-ILL GAS & ELEC.
KENTUCKY	ELMER SMITH	2	OWENSBORO MUN UTIL.
KENTUCKY	EW BROWN	2	KENTUCKY UTL CO.
KENTUCKY	EW BROWN	3	KENTUCKY UTL CO.
KENTUCKY	GHENT	1	KENTUCKY UTL CO.
MARYLAND	MORGANTOWN	1	POTOMAC ELEC PWR CO.
MARYLAND	MORGANTOWN	2	POTOMAC ELEC PWR CO.
MICHIGAN	JH CAMPBELL	1	CONSUMERS POWER CO.
MISSOURI	LABADIE	1	UNION ELECTRIC CO.
MISSOURI	LABADIE	2	UNION ELECTRIC CO.
MISSOURI	LABADIE	3	UNION ELECTRIC CO.
MISSOURI	LABADIE	4	UNION ELECTRIC CO.
MISSOURI	MONTROSE	1	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	2	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	3	KANSAS CITY PWR & LT.
NEW YORK	DUNKIRK	3	NIAGARA MOHAWK PWR.
NEW YORK	DUNKIRK	4	NIAGARA MOHAWK PWR.
NEW YORK	GREENIDGE	6	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	1	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	2	NY STATE ELEC & GAS.
OHIO	ASHTABULA	7	CLEVELAND ELEC ILLUM.
OHIO	AVON LAKE	11	CLEVELAND ELEC ILLUM.
OHIO	CONESVILLE	4	COLUMBUS STHERN PWR.
OHIO	EASTLAKE	1	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	2	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	3	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	4	CLEVELAND ELEC ILLUM.
OHIO	MIAMI FORT	6	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	5	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	6	CINCINNATI GAS & ELEC.
PENNSYLVANIA	BRUNNER ISLAND	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	CHESWICK	1	DUQUESNE LIGHT CO.
PENNSYLVANIA	CONEMAUGH	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	CONEMAUGH	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	PORTLAND	1	METROPOLITAN EDISON.
PENNSYLVANIA	PORTLAND	2	METROPOLITAN EDISON.
PENNSYLVANIA	SHAWVILLE	3	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	4	PENNSYLVANIA ELEC CO.
TENNESSEE	GALLATIN	1	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	2	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	3	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	1	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	2	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	3	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	5	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	6	TENNESSEE VAL AUTH.
WEST VIRGINIA	ALBRIGHT	3	MONONGAHELA POWER CO.
WEST VIRGINIA	FORT MARTIN	1	MONONGAHELA POWER CO.

TABLE 1—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
WEST VIRGINIA	MOUNT STORM	1	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	2	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	3	VIRGINIA ELEC & PWR.
WISCONSIN	GENOA	1	DAIRYLAND POWER COOP.
WISCONSIN	SOUTH OAK CREEK	7	WISCONSIN ELEC POWER.
WISCONSIN	SOUTH OAK CREEK	8	WISCONSIN ELEC POWER.

TABLE 2—PHASE I DRY BOTTOM-FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	COLBERT	1	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	2	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	3	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	4	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	5	TENNESSEE VAL AUTH.
ALABAMA	EC GASTON	1	ALABAMA POWER CO.
ALABAMA	EC GASTON	2	ALABAMA POWER CO.
ALABAMA	EC GASTON	3	ALABAMA POWER CO.
ALABAMA	EC GASTON	4	ALABAMA POWER CO.
FLORIDA	CRIST	6	GULF POWER CO.
FLORIDA	CRIST	7	GULF POWER CO.
GEORGIA	HAMMOND	1	GEORGIA POWER CO.
GEORGIA	HAMMOND	2	GEORGIA POWER CO.
GEORGIA	HAMMOND	3	GEORGIA POWER CO.
GEORGIA	HAMMOND	4	GEORGIA POWER CO.
ILLINOIS	GRAND TOWER	9	CEN ILLINOIS PUB SER.
INDIANA	CULLEY	2	STHERN IND GAS & EL.
INDIANA	CULLEY	3	STHERN IND GAS & EL.
INDIANA	GIBSON	1	PSI ENERGY INC.
INDIANA	GIBSON	2	PSI ENERGY INC.
INDIANA	GIBSON	3	PSI ENERGY INC.
INDIANA	GIBSON	4	PSI ENERGY INC.
INDIANA	RA GALLAGHER	1	PSI ENERGY INC.
INDIANA	RA GALLAGHER	2	PSI ENERGY INC.
INDIANA	RA GALLAGHER	3	PSI ENERGY INC.
INDIANA	RA GALLAGHER	4	PSI ENERGY INC.
INDIANA	FRANK E RATTS	1SG1	HOOSIER ENERGY REC.
INDIANA	FRANK E RATTS	2SG1	HOOSIER ENERGY REC.
INDIANA	WABASH RIVER	1	PSI ENERGY INC.
INDIANA	WABASH RIVER	2	PSI ENERGY INC.
INDIANA	WABASH RIVER	3	PSI ENERGY INC.
INDIANA	WABASH RIVER	5	PSI ENERGY INC.
IOWA	DES MOINES	11	IOWA PWR & LT CO.
IOWA	PRAIRIE CREEK	4	IOWA ELEC LT & PWR.
KANSAS	QUINDARO	2	KS CITY BD PUB UTIL.
KENTUCKY	COLEMAN	C1	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C2	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C3	BIG RIVERS ELEC CORP.
KENTUCKY	EW BROWN	1	KENTUCKY UTL CO.
KENTUCKY	GREEN RIVER	5	KENTUCKY UTL CO.
KENTUCKY	HMP&L STATION 2	H1	BIG RIVERS ELEC CORP.
KENTUCKY	HMP&L STATION 2	H2	BIG RIVERS ELEC CORP.
KENTUCKY	HL SPURLOCK	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	2	EAST KY PWR COOP.
MARYLAND	CHALK POINT	1	POTOMAC ELEC PWR CO.
MARYLAND	CHALK POINT	2	POTOMAC ELEC PWR CO.
MINNESOTA	HIGH BRIDGE	6	NORTHERN STATES PWR.
MISSISSIPPI	JACK WATSON	4	MISSISSIPPI PWR CO.
MISSISSIPPI	JACK WATSON	5	MISSISSIPPI PWR CO.
MISSOURI	JAMES RIVER	5	SPRINGFIELD UTL.
OHIO	CONESVILLE	3	COLUMBUS STHERN PWR.
OHIO	EDGEWATER	13	OHIO EDISON CO.
OHIO	MIAMI FORT [1]	5–1	CINCINNATI GAS&ELEC.
OHIO	MIAMI FORT [1]	5–2	CINCINNATI GAS&ELEC.
OHIO	PICWAY	9	COLUMBUS STHERN PWR.
OHIO	RE BURGER	7	OHIO EDISON CO.
OHIO	RE BURGER	8	OHIO EDISON CO.
OHIO	WH SAMMIS	5	OHIO EDISON CO.
OHIO	WH SAMMIS	6	OHIO EDISON CO.

TABLE 2—PHASE I DRY BOTTOM-FIRED UNITS—Continued

State	Plant	Unit	Operator
PENNSYLVANIA	ARMSTRONG	1	WEST PENN POWER CO.
PENNSYLVANIA	ARMSTRONG	2	WEST PENN POWER CO.
PENNSYLVANIA	MARTINS CREEK	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	MARTINS CREEK	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SHAWVILLE	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SUNBURY	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SUNBURY	4	PENNSYLVANIA PWR & LT.
TENNESSEE	JOHNSONVILLE	7	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	8	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	9	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	10	TENNESSEE VAL AUTH.
WEST VIRGINIA	HARRISON	1	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	2	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	3	MONONGAHELA POWER CO.
WEST VIRGINIA	MITCHELL	1	OHIO POWER CO.
WEST VIRGINIA	MITCHELL	2	OHIO POWER CO.
WISCONSIN	JP PULLIAM	8	WISCONSIN PUB SER CO.
WISCONSIN	NORTH OAK CREEK [2]	1	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	2	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	3	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	4	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	5	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	6	WISCONSIN ELEC PWR.

[1] Vertically fired boiler.
[2] Arch-fired boiler.

TABLE 3—PHASE I CELL BURNER TECHNOLOGY UNITS

State	Plant	Unit	Operator
INDIANA	WARRICK	4	STHERN IND GAS & EL.
MICHIGAN	JH CAMPBELL	2	CONSUMERS POWER CO.
OHIO	AVON LAKE	12	CLEVELAND ELEC ILLUM.
OHIO	CARDINAL	1	CARDINAL OPERATING.
OHIO	CARDINAL	2	CARDINAL OPERATING.
OHIO	EASTLAKE	5	CLEVELAND ELEC ILLUM.
OHIO	GENRL JM GAVIN	1	OHIO POWER CO.
OHIO	GENRL JM GAVIN	2	OHIO POWER CO.
OHIO	MIAMI FORT	7	CINCINNATI GAS & EL.
OHIO	MUSKINGUM RIVER	5	OHIO POWER CO.
OHIO	WH SAMMIS	7	OHIO EDISON CO.
PENNSYLVANIA	HATFIELDS FERRY	1	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	2	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	3	WEST PENN POWER CO.
TENNESSEE	CUMBERLAND	1	TENNESSEE VAL AUTH.
TENNESSEE	CUMBERLAND	2	TENNESSEE VAL AUTH.
WEST VIRGINIA	FORT MARTIN	2	MONONGAHELA POWER CO.

APPENDIX B TO PART 76—PROCEDURES AND METHODS FOR ESTIMATING COSTS OF NITROGEN OXIDES CONTROLS APPLIED TO GROUP 1, BOILERS

1. PURPOSE AND APPLICABILITY

This technical appendix specifies the procedures, methods, and data that the Administrator will use in establishing ‘‘***the degree of reduction achievable through this retrofit application of the best system of continuous emission reduction, taking into account available technology, costs, and energy and environmental impacts; and which is comparable to the costs of nitrogen oxides controls set pursuant to subsection (b)(1) (of section 407 of the Act).’’ In developing the allowable NO_X emissions limitations for Group 2 boilers pursuant to subsection (b)(2) of section 407 of the Act, the Administrator will consider only those systems of continuous emission reduction that, when applied on a retrofit basis, are comparable in cost to the cost in constant dollars of low NO_X burner technology applied to Group 1, Phase I boilers.

The Administrator will evaluate the capital cost (in dollars per kilowatt electrical ($/kW)), the operating and maintenance costs (in $/year), and the cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology controls over a range of boiler sizes (as measured by the gross electrical capacity of the associated generator in megawatt electrical (MW)) and utilization rates (in percent gross nameplate capacity on an annual basis) to develop estimates of the capital costs and cost effectiveness for Group 1, Phase I boilers. The following units will be excluded from these determinations of the capital costs and cost effectiveness of NO_X controls set pursuant to subsection (b)(1) of section 407 of the Act: (1) Units employing an alternative technology, or overfire air as applied to wall-fired boilers or separated overfire air as applied to tangentially fired boilers, in lieu of low NO_X burner technology for reducing NO_X emissions; (2) units employing no controls, only controls installed before November 15, 1990, or only modifications to boiler operating parameters (e.g., burners out of service or fuel switching) for reducing NO_X emissions; and (3) units that have not achieved the applicable emission limitation.

2. AVERAGE CAPITAL COST FOR LOW NO_X BURNER TECHNOLOGY APPLIED TO GROUP 1 BOILERS

The Administrator will use the procedures, methods, and data specified in this section to estimate the average capital cost (in $/kW) of installed low NO_X burner technology applied to Group 1 boilers.

2.1 Using cost data submitted pursuant to the reporting requirements in section 4 below, boiler-specific actual or estimated actual capital costs will be determined for each unit in the population specified in section 1 above for assessing the costs of installed low NO_X burner technology. The scope of installed low NO_X burner technology costs will include the following capital costs for retrofit application: (1) For the burner portion—burners or air and coal nozzles, burner throat and waterwall modifications, and windbox modifications; and, where applicable, (2) for the combustion air staging portion—waterwall modifications or panels, windbox modifications, and ductwork, and (3) scope adders or supplemental equipment such as replacement or additional fans, dampers, or ignitors necessary for the proper operation of the low NO_X burner technology. Capital costs associated with boiler restoration or refurbishment such as replacement of air heaters, asbestos abatement, and recasing will not be included in the cost basis for installed low NO_X burner technology. The scope of installed low NO_X burner technology retrofit capital costs will include materials, construction and installation labor, engineering, and overhead costs.

2.2 Using gross nameplate capacity (in MW) for each unit as reported in the National Allowance Data Base (NADB), boiler-specific capital costs will be converted to a $/kW basis.

2.3 Capital cost curves ($/kW versus boiler size in MW) or equations for installed low NO_X burner technology retrofit costs will be developed for: (1) Dry bottom wall fired boilers (excluding units applying cell burner technology) and (2) tangentially fired boilers.

3. [RESERVED]

4. REPORTING REQUIREMENTS

4.1 The following information is to be submitted by each designated representative of a Phase I affected unit subject to the reporting requirements of §76.14(c):

4.1.1 Schedule and dates for baseline testing, installation, and performance testing of low NO_X burner technology.

4.1.2 Estimates of the annual average baseline NO_X emission rate, as specified in section 3.1.1, and the annual average controlled NO_X emission rate, as specified in section 3.1.2, including the supporting continuous emission monitoring or other test data.

4.1.3 Copies of pre-retrofit and post-retrofit performance test reports.

4.1.4 Detailed estimates of the capital costs based on actual contract bids for each component of the installed low NO_X burner technology including the items listed in section 2.1. Indicate number of bids solicited. Provide a copy of the actual agreement for the installed technology.

4.1.5 Detailed estimates of the capital costs of system replacements or upgrades such as coal pipe changes, fan replacements/upgrades, or mill replacements/upgrades undertaken as part of the low NO_X burner technology retrofit project.

4.1.6 Detailed breakdown of the actual costs of the completed low NO_X burner technology retrofit project where low NO_X burner technology costs (section 4.1.4) are disaggregated, if feasible, from system replacement or upgrade costs (section 4.1.5).

4.1.7 Description of the probable causes for significant differences between actual and estimated low NO_X burner technology retrofit project costs.

4.1.8 Detailed breakdown of the burner and, if applicable, combustion air staging system annual operating and maintenance costs for the items listed in section 3.3 before and after the installation, shakedown, and/or optimization of the installed low NO_X burner technology. Include estimates and a description of the probable causes of the incremental annual operating and maintenance costs (or savings) attributable to the installed low NO_X burner technology.

4.2 All capital cost estimates are to be broken down into materials costs, construction and installation labor costs, and engineering and overhead costs. All operating and maintenance costs are to be broken down into maintenance materials costs, maintenance labor costs, operating labor costs, and fan electricity costs. All capital and operating costs are to be reported in dollars with the year of expenditure or estimate specified for each component.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67164, Dec. 19, 1996; 62 FR 3464, Jan. 23, 1997]

PART 77—EXCESS EMISSIONS

Sec.

AUTHORITY: 42 U.S.C. 7601 and 7651, et seq.

SOURCE: 58 FR 3757, Jan. 11, 1993, unless otherwise noted.

§ 77.1 Purpose and scope.

(a) This part sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, *et seq.*, as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program.

(b) Nothing in this part shall limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended. Any allowance deduction, excess emission penalty, or interest required under this part shall not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Act.

§ 77.2 General.

Part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (Federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired units exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part. The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 77.3 Offset plans for excess emissions of sulfur dioxide.

(a) *Applicability*. The owners and operators of any affected source that has excess emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the source's compliance account.

(b) *Deadline.* Not later than 60 days after the end of any calendar year during which an affected source had excess emissions of sulfur dioxide (except for any increase in excess emissions under § 72.91(b) of this chapter), the designated representative for the source shall submit to the Administrator a complete proposed offset plan to offset those emissions. Each day after the 60-day deadline that the designated representative fails to submit a complete proposed offset plan shall be a separate violation of this part.

(c) *Number of Plans.* The designated representative shall submit a proposed offset plan for each affected source with excess emissions of sulfur dioxide.

(d) *Contents of Plan.* A complete proposed offset plan shall include the following elements in a format prescribed by the Administrator for the source and for the calendar year for which the plan is submitted:

(1) Identification of the source.

(2) If the source had excess emissions for the calendar year prior to the year for which the plan is submitted, an explanation of how and why the excess emissions occurred for the year for which the plan is submitted and a description of any measures that were or will be taken to prevent excess emissions in the future.

(3) At the designated representative's option, the number of allowances to be deducted from the source's compliance account's to offset the excess emissions for the year for which the plan is submitted.